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Climate change risks in electricity networks

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Climate change as forecast by UKCP09 will affect the planning and operation of power transmission and distribution systems in Great Britain. The links between climate change and networks are identified. The risk of flooding is very likely to increase, with the greatest effect if substations are inundated. The optimal size and location of electricity transmission corridors is difficult to define because of uncertainty in the seasonal, regional and absolute changes to wind-speed and corresponding wind generation. Although equipment in Great Britain is already fundamentally designed to operate in the future conditions anticipated under climate change, marginal changes to the capabilities of equipment will need to be accounted for in parameters used in network planning procedures. The indirect effect of climate change, created by the political response designed to minimise greenhouse gas emissions, will be more significant than the direct impact of a changing climate. This will dramatically change the generation mix, overall demand and both seasonal and diurnal demand profiles. An industry with a wider range of tools and technical solutions for planning and operation will be more prepared to manage capacity, stability and reliability at lower cost than if present methods do not evolve.

Introduction

Power is transmitted and distributed across Great Britain (GB) from a wide range of generation plant types to industrial, commercial and domestic customers. These networks are composed of assets comprising overhead lines and underground cables, which connect substations containing transformers, switches and control equipment. The transmission network transfers bulk quantities of power at voltages of 400 and 275 kV in England and Wales, with 132 kV additionally used in Scotland. The transmission system operators are responsible for balancing supply and demand while also maintaining reserves in case of exceptional events. Distribution networks take power from the transmission network at grid supply points and then cascade through a series of voltage transformations at substations to the final customer connections.

At higher voltage levels, the system is built with more redundancy so it is able to cope with equipment failures and maintenance periods without interrupting customers' supplies. These networks are meshed, so that power can be routed through a number of paths, which provides redundancy, flexibility and resilience. At the lowest voltage levels (domestic supply), there is often no redundancy, but far fewer customers are affected if a fault occurs. The variety of network types also varies more at the further reaches of the distribution network. At one extreme, there are dense urban areas where the quantity of customers demands the highest levels of reliability. At the other, sparse, radially fed, rural populations can experience interruptions to supply from time to time. This is largely a consequence of network design standards that dictate the required levels of redundancy based on the level of demand.

The effects brought about by climate change will have a substantial impact on the electricity supply system. Of at least equal weight to the direct impacts of climate change, political decisions will be a major factor in the evolution of the power system in response to climate change (Mideksa and Kallbekken, 2010). The Climate Change Act of 2008 (UK Parliament, 2008) declared legally binding targets for the UK's contribution to climate change, requiring fundamentally an 80% reduction in 1990 levels of greenhouse gases by 2050. This is a significant decrease in the UK's overall emissions, and achieving such a reduction presents real challenges to the operation, planning and investments of a power system that will effectively require complete decarbonisation.

As a backdrop to climate change considerations, since the start of deregulation in 1990, the transmission and distribution (T&D) systems have been in a state of considerable change. Challenges have emerged from the need to manage ageing infrastructure (some substation equipment from the 1950s and steel towers and underground cables from the 1930s remain in service) and the political response to climate change, typified by significant increases in generation capacity installed in the distribution network. When examining the broader or 'indirect' effects of climate change on the power system, the substantial interdependence of electricity systems with their physical, social, environmental and political surroundings rapidly becomes apparent (Hammond *et al.*, 2013).

To identify the effects of climate change on the power system, this paper continues with a brief review of several climate change adaptation reports. The potential effects of climate change on T&D networks are considered from the existing records of weather-related faults. The specific effects of anticipated climate variation on relevant assets are then described. Next, trends in the evolution of the power system, largely driven by actions designed to minimise climate change, are discussed. This paper has some overlap with other reviews in this issue; further reading can be found on renewable generation (Cradden, 2015), conventional generation (Byers and Amezega, 2015) and electricity demand (Wood, 2015).

Climate change adaptation reports

In response to the Climate Change Act, a number of organisations were required to produce Climate Change Adaptation Reports; for T&D system operators, their industry body, the Energy Networks Association (ENA), produced a Climate Change Adaptation Report in 2011 (ENA, 2011). This report identifies the main impacts from climate change projections to be increased temperature, increased winter rainfall, summer drought, sea level rise and storm surge. They do not find firm evidence for increased wind intensity or ice storms. Increasing temperature will reduce the current carrying capacity of network assets by up to 10% (3%) for overhead lines in distribution (transmission) networks, 4% (5%) for underground cables in distribution (transmission) networks and 7·5% (5%) for distribution (transmission) transformers. In response to recent flooding incidents and increased risk in the future, engineering technical report ETR138 (ENA, 2009) has resulted in a 10-year programme of work to improve substation resilience to flooding.

The ENA has worked with the UK Met Office to produce the EP2 report (the impact of climate change on the UK energy industry), which seeks to better understand the impact that predicted climate change will have on the electricity networks. One published branch of this work (McColl *et al.*, 2012) has determined that the risk of lightning faults to the network is projected to increase in the future. Wind and gale faults occur frequently, but uncertainty in future climate projections of wind means that how this risk may change in the future cannot be quantified. Snow and ice accretion may decrease in the future due to fewer days of snow, but when it does snow, the intensity of the event may be the same or increase.

Pricewaterhouse Coopers have reported on adapting to climate change in the infrastructure sectors (Pricewaterhouse Coopers, 2010). The Royal Academy of Engineering identifies a range of future vulnerabilities for power systems in their Infrastructure, Engineering and Climate Change Adaptation report (Royal Academy of Engineering, 2011). The UK government's Climate Change Risk Assessment (Department for the Environment, Food and Rural Affairs, 2012) identifies the key risks of relevance to electricity networks as flooding, higher cooling demand and heat damage. An opportunity in reduced demand for heating is acknowledged.

Potential impacts of climate change

Alongside reports of the type referred to above, there is a growing body of work aiming to understand the risks and impacts of climate change on power systems. Before detailing the potential effects of projected climate change, how today's climate and weather affects the UK T&D networks is considered.

Weather and environment-related incidents are potentially most severe when they affect the higher voltage (400 kV, 275 kV) transmission network, or the highest voltage (132 kV) of the distribution network. However, such incidents are infrequent because of the relative robustness of construction of higher voltage networks. They are also less likely to cause customer disconnection, as there is generally a wide choice of alternative routes.

Incidents on the distribution network are more frequent, and increasingly frequent at lower voltages. For example, during a typical year (2009–2010), the number of incidents on the 132-kV network (transmission in Scotland, distribution in England and Wales) was 751 (ENA, 2010). This can be compared with 2583 incidents at distribution high voltages (HV, 66 kV, 33 kV), 28 313 incidents at medium voltages (MV, typically 11 kV) and 145 203 incidents at low voltages (LV, 0·4 kV). Only incidents in which customer disconnection exceeds 3 minutes are reported. Moreover, the lower the voltage, the more likely it is to disconnect customers, and the longer that disconnection is likely to last because of decreased alternative supply routes. These data are shown in Table 1. In terms

Voltage	No. of incidents	Proportion of incidents disconnecting customers	Average no. of customers disconnected	Average disconnection time: min	Product (million customer minutes lost)
HV	2583	25%	2314	38	57
MV	28 313	92%	539	76	1067
LV	145 203	98%	20	205	583

Table 1. The number and duration of customer disconnections at different voltage levels on the UK transmission and distribution networks for 2009–2010 (ENA, 2010)

of overall impact (the product of the four middle columns), it can be seen that MV has the greatest impact, and subsequent analysis will apply to that voltage level alone. This is further justified in that the proportion of incidents caused by weather or environmental factors (25%) is greater than the proportion at HV (20%) or at LV (9%).

Of 7134 incidents per year at MV caused by weather or the environment, the class with greatest frequency was incidents caused by lightning strike (2185). This was followed by wind, including windborne materials (1535), trees (1320), and snow and ice (1285). Relatively infrequent were incidents caused by rain or flooding (165) or by solar heat (50). However, these relative frequencies must be multiplied by likely severity of the consequences to assess the relative impact. A lightning strike will usually cause no permanent damage, and power to customers can often be restored by automatic switch reclosing within a few minutes. By contrast, following flooding, supply cannot easily be restored and may cause customer disconnection for several days. The highest impact would arise from flooding of a major 400/132 kV or 132/33 kV substation, as the network design standards relate to redundancy of circuits, not substations, making substations vulnerable under single failure. Recovery time from such a loss could extend into weeks, with permanent repairs taking many months. Emergency interventions might need to include mobile generation or construction of temporary circuits.

One way to reduce the number of incidents could be undergrounding. While 48% of the MV network is underground, only 27% of incidents occur on underground cables. The 52% of the MV network, which is overhead, however, accounts for 41% of incidents, around half as much again (the other 32% of incidents occur at substations).

Finally, the question arises of how to cost any increase (or decrease) in climate-related incidents. Earlier analysis (Blake *et al.*, 2013) suggested a metric of total network risk (TNR), measured in expected thousands of pounds at a given location or section of the network (Maslin and Austin, 2012). This metric includes direct repair costs following an incident, indirect costs including possible shortening of asset lifetimes, and customer disconnection costs (based on frequency and duration) as levied by the regulator on the distribution network operators (DNOs). This metric, and others like it, have proven useful in enabling DNOs to determine which of a number of possible mitigation strategies would be cost-effective.

Following this description of the present situation, the next section addresses the expected direct effects of climate change on power systems.

Climatic variation

Electricity infrastructure has a long operational lifetime, often at least 30–40 years. It is important, therefore, to understand how assets will perform over these durations. Assets built now, and those already in place, will be expected to operate long into the future, potentially in a different environment to the one in which they currently operate. UK climate projections (UKCP09, 2011) indicate that mean temperatures are likely to rise by 2°C–3°C by 2050. It is suggested that this could lead to reductions in conductor ratings, particularly during the summer (Cradden and Harrison, 2013).

Extreme events

There is evidence linking climate change to extreme weather events (Coumou and Rahmstorf, 2012) and that extreme weather has an adverse effect on power system reliability (Billinton and Acharya, 2006). Different extreme weather events can impact the power system in different ways, and some events are easier to mitigate than others.

Flooding

The UKCP09 predictions suggest that, in all emission scenarios, there is a reasonable likelihood of increased rainfall, which could lead to increased flooding (UKCP09, 2011). Abi-Samra (Abi-Samra and Malcolm, 2011) suggests that flooding is the most significant extreme weather event because of its long-term consequences. Flash floods are particularly troubling because they occur with little warning; experience from Boscastle in 2004 shows the impact that can result. River floods, which are more common in the UK, are more gradual, and consequently, responsive action can be taken to mitigate their impact. The major concern is flooding of substations, where sensitive equipment can come into contact with flood waters. Suggested countermeasures include waterproofing the substation, flood protecting individual existing assets, installing perimeter flood protection and promoting off-site flood mitigation works that also benefit the wider community. The example in Figure 1 shows a substation with a nearby flood culvert. In coastal areas rainfall will be compounded by sea-level rise, particularly when combined with storm surge.

Heat waves

Heat waves are currently not common in the UK, but if temperatures increase in both their average value and variability, it is likely that heat waves will increase in frequency and severity. A study in California suggests that heat waves can cause distribution transformer failures (Abi-Samra *et al.*, 2010). The study shows that more transformers failed during a heat wave than during the entire preceding year. Higher temperatures also lead to de-rating of overhead lines, as the maximum sag is determined by legally binding minimum ground clearances.

Precipitation

Climate predictions suggest that the UK will have a reduced level of precipitation during the summer. Reduced soil moisture increases soil thermal resistivity, which results in reduced heat transfer from underground cables. Droughts, caused by a reduction in precipitation, would lead to an increased likelihood of underground cables overheating (Abi-Samra *et al.*, 2010).

Earthing systems will be affected by reduced soil moisture. This will reduce the electrical conductivity of the soil and so require

Figure 1. A UK substation moated by floodwater from the nearby River Severn. Image Copyright Jonathan Billinger. This work is licensed under the Creative Commons Attribution-Share Alike 2.0 Generic Licence (Creative Commons).

reassessment of the assumptions made in earthing system design. This is discussed in the ENA's Climate Change Adaptation Report (ENA, 2011).

Wind speed

UKCP09 wind projections suggest that average summer wind speeds are likely to decrease, while average winter wind speeds may increase but are as likely to decrease or remain the same (Sexton and Murphy, 2010). However, this projection comes with a 'health warning' due to the high levels of uncertainty. A study based on regional climate models of northern Europe, with boundary conditions informed by a global climate model, indicates that in the North Sea region, wind energy density, which is dependent on wind speed, is likely to increase both on average and in winter, but decrease in summer (Hueging *et al.*, 2013). The study also found that wind energy density is already highly variable, with changes of up to 19% annually, a result that is verified by other wind resource studies looking at large-scale phenomena (Brayshaw *et al.*, 2011). It is suggested that climate change could further increase this variability (Hueging *et al.*, 2013; Pryor and Barthelmie, 2010).

Wind speed affects the power system in a number of ways: when the wind blows, conductors and transformers are cooled by forced convection (Michiorri *et al.*, 2009) and wind generation produces electricity. If the wind generation is connected at distribution level, this can result in customers being supplied by the local generation, alleviating the congestion on the network (Wang *et al.*, 2010). Conversely, if the wind farm is much larger than the local load, this can result in reverse power flow, which could increase congestion. At high wind speeds (usually 25 m/s), wind generation cuts out to avoid damage to the turbines (Burton *et al.*, 2011). This could result in a sudden deficit in generation, which would need to be resupplied using conventional plant or interconnection. Because the conventional generation and DG are likely to be in different areas of the network, this could result in power flow volatility (National Grid, 2013).

High winds are likely to result in damage, though usually due to wind-blown debris interfering with the system, rather than lines and towers themselves being damaged by the wind directly (Abi-Samra and Malcolm, 2011). The increased failure rate on overhead lines with large numbers of trees nearby, is being mitigated by a resilience vegetation management programme legislated in the 2006 amendment to the ESQC (Electricity, Safety, Quality and Continuity) regulations (Department of Trade and Industry, 2006). The ENA (ENA, 2011) highlight that increased temperature and sunlight will cause increased vegetation growth, so the management task will become more significant. While there are currently no clear indications of future increases in maximum wind speeds in UK, if such were to emerge, it would have significant implications on the structural design of existing and future overhead lines.

Cloud cover

The UKCP09 climate predictions (UKCP09, 2011) indicate that the amount of cloud is likely to increase in winter, while it may decrease in summer. A decrease in cloud cover during the summer could lead to greater energy yield from photovoltaic (PV) panels. This can provide benefits to the network by supplying customers directly and hence reducing the load on circuits. However, it can also provide problems, such as rising voltages at the end of distribution feeders and undesired harmonics arising from the use of power electronic converters. The impact of PV on distribution systems is discussed in detail by Thomson and Infield (2007). While the energy yield of PV would increase with reduced cloud cover, the peak output – which the majority of network problems are a consequence of – would not, unless increased yields stimulate a higher install rate (see below).

Spatial variability

The UKCP09 projections (UKCP09, 2011) suggest that changes in climate will not occur uniformly across the UK. Increases in temperature are expected to be more prevalent in the south of England, increasing the already present temperature difference across the country. Changes in precipitation, both increases in winter and decreases during the summer, are also expected to be more pronounced in the south of England. Conversely, changes in mean wind speed, particularly in the winter, seem more likely to occur in the north of Scotland, although the predictions have a high level of uncertainty as to which will occur, suggesting an increased level of variability. An increase in the variability of wind speeds in Scotland is likely to be detrimental to power system operation, given that much of the UK's wind generation is situated in Scotland. More extreme temperature changes in the south of England imply that there is likely to be an increase in the volume of electric power transmitted from north to south due to increased heating demands in winter and air conditioning demands during the summer.

System trends

Of the three central categories (Chandramowli and Felder, 2014) in which climate change can produce impact, the direct impact of climate change on the frequency and severity of fault incidents on power system components has already been discussed The remaining two categories of policy impacts – market reforms and regulation, and the uncertainties surrounding climate change predictions – are the focus of this section.

A significant body of work has been developed in investigating the UK's transition to a low-carbon economy. The DECC 2050 Pathways project (Department of Energy and Climate Change, 2010), LENS 2050 (Ault *et al.*, 2008), UKERC's Energy 2050 project (Ekins, 2009), SuperGen Networks 2050 (Elders *et al.*, 2006) and the analysis of Barnacle *et al.* (2013) are just some of the analyses available. Each of these analyses typically employs a reference scenario where networks, generation and demand evolve in a 'business as usual' (BaU) manner. Comparator scenarios show greater flexibilities in market reform, generation technologies and demand side engagement.

All the scenarios have differing impacts on the T&D systems in the UK. Those close to BaU display reliance on increasing efficiencies of conventional plant such as coal and gas combined with carbon capture and storage. Such scenarios have a strong influence on capacity at the transmission level, as well as increased interconnection. At the other end of the spectrum, consumers become 'prosumers' (producers and consumers) where domestic-level generation is combined with highly integrated demand side participation (DSP) schemes, resulting in further shift of the generation bias towards the distribution networks.

Under the 'Transition Pathways' narratives of Barnacle *et al.* (2013), the 'Market Rules' BaU scenario has been shown to have significant impacts on the balancing of supply and demand, with a generation surplus of 19 GW on the UK system in a scenario with no DSP. This number reduces to 9 GW with the presence of DSP, though this remains significantly larger than the predicted 2050 interconnection capacity of 6·81 GW. This scenario also generates the highest peak demand at around 83 GW, far greater than that shown in the most socially inclusive scenario 'Thousand Flowers' with a peak demand of around 38 GW. Both these values are reduced to 73 and 27 GW, respectively, when DSP is employed. The 'Thousand Flowers' scenario does, however, generate significant generation surplus values of around 44 and 28 GW for non-DSP and DSP situations, again far higher than the predicted capability of interconnection (Barnacle *et al.*, 2013).

The wider power system, in response to these challenges, has developed a number of possible pathways for evolution (McDonald, 2008). In an effort to manage increasing system complexity, distributed control techniques have been developed, centring on local measurements to inform decisions. The advance of artificial intelligence and machine learning techniques has led to the concept of an autonomic power system (McArthur *et al.*, 2012). The smart grid philosophy aims to improve reliability and efficiency, reduce costs, and increase network capacity while maintaining the same level of system security.

As smart grid alternatives are implemented, the network is likely to become more complex and more interconnected. This complexity brings its own increase in risk. One of these, in particular at transmission level, is an increasing likelihood of cascading failure, where one incident has rapid knock-on effects across an entire network leading to widespread blackouts (Newman *et al*., 2011; Vaiman *et al.*, 2012). Another possible increased risk, as the network becomes increasingly reliant on whole-network control systems, is of communication or control system failure, either accidental or as a consequence of malicious cyber-attack.

Generation

Emissions reduction targets across the world have led to the decommissioning of conventional fossil-fuel-generating plant and an increase in the installed capacity of renewable generation sources. In the UK, the majority of these new sources have been in the form of wind power (Department of Energy and Climate Change, 2013).

It is forecast that there will be an increased proportion of nuclear generation and a greatly increased proportion of renewables. This may be affected by the use of clean coal, if the technologies can be proven effective. As regards T&D, the substitution of nuclear or clean coal generation for coal and gas is unlikely to have a significant overall effect. It is unlikely to be possible to site new large generating stations close to demand. They are likely to be in remote locations (for example, on the sites of previous nuclear generation) for political reasons, so the transmission of large amounts of electricity over long distances ('coal by wires') is likely to continue unchanged.

This is likely to be exacerbated by the location of large wind farms in remote locations, both onshore (e.g. in northern Scotland) and offshore (e.g. in the North Sea). Construction of new transmission lines and undersea cables will be required to move electrical energy from where it is produced to where it is consumed. The same would apply to any large marine schemes such as tidal barrages.

As well as the continued dependence on remote bulk generation, the geographic location of renewable generating capacity, in combination with the Government's Feed in Tariff (FIT) policy and other incentives has led to a significant increase in installed capacity within the distribution network. The initial PV FIT rollout demonstrated the impact of climate change policy on the electricity networks with a significantly biased increase in the uptake of PV generation at the domestic level (Maslin and Austin, 2012). Similar experiences have been observed in Italy (Antonelli and Desideri, 2014).

Increasing temperatures are associated with a probable decrease in cloud cover that would lead to increased energy yields from small-scale PV. This would improve the case for adopting PV, driving increases in installed capacity. Less certain is whether wind speeds would increase, leading to increases in the level of penetration of small-scale wind (Wang *et al.*, 2012).

Managing a transmission system with a high penetration of such generation presents significant challenges to maintain reliable and secure services to customers. It has been suggested that in some scenarios that traditional 'base-load' generation may be forced to operate at lower efficiencies, affecting asset lifetimes and leading to an increased risk of faults (Troy *et al.*, 2010).

Demand

There is likely to be extensive electrification of transport (electric vehicles replacing diesel and petrol) and of space heating (heat pumps replacing natural gas). The extent of this substitution could be as great as a tripling of overall electrical energy demand (Barton *et al.*, 2013; Blokhuis *et al.*, 2011; Sugiyama, 2012; Wang *et al.*, 2012). As well as the electrification of existing loads, new types of load can be expected, which may be essentially independent of climate change (e.g. digital applications) or may be a direct consequence, in particular space cooling. This substantial increase in demand would, on its own, require extensive reinforcement of distribution networks across the country and at all voltage levels. However, these new technologies have the potential to provide DSP services, helping to offset the negative aspects of their high power consumption. The adoption of CHP units as opposed to HP, devices can help to reduce peak consumption by generating electricity onsite at the same time as meeting heat demand.

Electricity demand in the UK currently peaks during the winter months (Greenwood *et al.*, 2014; National Grid, 2013); in most parts of the UK, winter peak loads are up to 50% higher than summer peaks. This is helpful to the system operator because conductor ratings are set seasonally, with the winter rating being the highest due to the low ambient temperatures (ENA, 1986; National Grid, 2013). In addition to making best use of the varying asset capacity, this also allows network maintenance to be carried out in summer months at lower risk. However, as temperatures increase, increased use of space cooling may cause the peak to shift into the summer. In some city centre areas, this difference has already disappeared, and there may even be a summer peak due to space cooling requirements. In warmer climates, a significantly higher summer peak is seen for this reason (Denholm and Hand, 2011). This would be detrimental to system operation because there is strong evidence that in summer peaking power systems, demand is highly correlated with ambient temperature (Franco and Sanstad, 2008; Pardo *et al.*, 2002; Valor *et al.*, 2001). Consequently, assets would be most heavily loaded during the hottest periods, increasing the chances of equipment failures.

Adaptation opportunities

Within the UK, supply and demand can be balanced more effectively by the use of storage, either electrical in the form of batteries (Denholm and Hand, 2011; Wang *et al.*, 2012), or using other media such as hydrogen (Ozbilen *et al.*, 2012) or thermal (Denholm *et al.*, 2012). There are system benefits to be gained across the T&D networks from energy storage, ranging from offsetting the need for peaking plant to preventing over-voltage in LV networks. Realising these benefits under the current market, regulatory and cost conditions is challenging but will become easier as the understanding of the role for storage and the market and regulatory conditions improve (Anuta *et al.*, 2014).

Possible smart grid interventions that could assist coping more effectively and efficiently with the pressures of climate change include real-time thermal ratings (RTTRs) (Cradden and Harrison, 2013; Greenwood and Taylor, 2014) – shown in Figure 2 – smart buildings, demand side management, network automation and operational ingenuity (Wang *et al.*, 2012). On the transmission side, high-voltage direct current, Flexible AC Transmission Systems (FACTS) and superconductor cables are a medium-term possibility (Buijs *et al.*, 2011). And, looking to the distant 2080 horizon, technologies that are at present only conceptual could become a reality, including nuclear fusion, geo-engineering, solar energy from outer space, and a world-encircling hydrogen super grid (Hoffert *et al.*, 2002).

Other possible interactions with the potential to balance energy generation and load are commercial rather than technical and include emissions trading (Wang *et al.*, 2012). Besides the technical balance between supply, storage and demand, there is a parallel

Figure 2. Weather monitoring on an HV power line for Real-Time Thermal Ratings. Image Copyright Jialiang Yi. This work is licensed under the Creative Commons Attribution-Share Alike 2.0 Generic Licence (Creative Commons)

management or political balancing act between security of supply, energy costs and environmental protection (Bazilian *et al.*, 2011). Again, this highlights the sensitivity of the overall energy system to the decisions of policy makers.

The cost of impacts

The cost for decarbonisation represents an enormous proportion of the European energy budget. It has been suggested that between 2010 and 2035, 70% of Europe's energy investment will be made in the electricity sector (Clastres, 2011).

New assets represent a significant investment, incorporating raw materials, removal of the existing asset(s), construction and commissioning costs and at lower voltage levels of the distribution network, are likely to result in loss of supply to customers. While weather effects have been shown to be the most significant aspect when considering power system failures, the second highest contributor has been found to lie in maintenance or in asset management (Boston, 2013). The smart grid philosophy seeks a reduction in network costs by maximising the use of existing assets through smart technologies and techniques such as the latent network capacity unlocked by RTTR.

Only considering the result of installing assets does not represent the complete carbon impact; the manufacturing and transport of new assets cannot be ignored. Since climate change scenarios are being evolved and developed constantly, coupled with the fact that power system components typically have long operational lifetimes, the installation of new assets represents a 'locked-in' investment decision, with limited possibility for resizing once installed.

Traditional investment as part of the revenue price index (RPI-X) regulation mechanism has been altered with the introduction of RIIO (Revenue = Incentives + Innovation + Outputs) mechanism, which places innovation at the heart of investment for the DNOs. This reflects the emerging system trends with power networks evolving to smart girds with increased decentralization.

Interconnections

Interconnection between wide-area power systems can help to improve overall system stability and reliability, ensuring that customers' supplies are maintained even with increased quantities of variable generation (Denny *et al.*, 2010). However, it has also been shown that while emissions are potentially reduced within one system, the knock-on effect could increase emissions in another, resulting in a net stalemate with regard to emissions (Denny *et al.*, 2010). Although helping manage demand and generation variability, interconnection can bring the potential for substantial disruption from cascading blackouts such as those seen in 2003 in Italy, the USA and Canada (Andersson *et al.*, 2005; Berizzi and IEEE, 2004).

The UK has electrical interconnectors to France, Ireland and the Netherlands, with planned interconnectors to Belgium and Norway, and possible future interconnectors over greater distances, such as to Iceland. In conjunction with transcontinental interconnectors elsewhere, this permits both import and export energy transfers, that could potentially connect the UK to systems including PV generation in North Africa (Brancucci Martínez-Anido *et al.*, 2013a, 2013b). This could well become a significant component of the national energy balance in a world responding to climate change.

Summary

The indirect effect of climate change, created by the political response designed to minimise greenhouse gas emissions, will be more significant than the direct impact of a changing climate. This will dramatically change the generation mix, overall demand and both seasonal and diurnal demand profiles. Complete decarbonisation of the electricity supply chain will change the characteristics of the generation plant and switch demand from fuels for transport and heating to the electricity networks.

Direct effects from climate change are expected to be gradual, and it is unlikely that a step change in the performance of network assets will take place. Equipment is already designed to operate in the conditions anticipated under future climate change. However, DNOs do exploit the greater peak and cyclic ratings that can be achieved at lower ambient temperatures. These changes to the capabilities of equipment will need to be accounted for in some parameters used in network planning procedures.

The risk of flooding is very likely to increase. This will have the greatest effect if substations become inundated any more than very infrequently as is the case at the moment. Because this is a problem that is already apparent, the industry has an ongoing programme to improve the resilience of electricity infrastructure to flooding.

Extended periods of low rainfall in the summer months will lead to drier soil that is less able to dissipate heat from underground cables. This could lead to a need to reduce the current carrying capacity in network design.

The number of lightning strikes is expected to increase, with a corresponding increase in overhead line faults. This could be addressed by undergrounding circuits, but this solution would not be cost-effective, and the capacity issue from drier soil noted above would further reduce the favourability of this solution.

Considerable uncertainty in the seasonal, regional and absolute changes to wind-speed results in corresponding uncertainty in the contribution of wind generation, both spatially and temporally. Wind installations are necessarily distant from load centres, so this could have a substantial impact on the optimal size and location of major electricity transmission assets.

The principal direct climate effect on demand that affects the networks is the move from a winter peaking system, when asset capacities are highest, to a summer peaking system due to air conditioning, when asset capacities are lower. This also creates problems in maintenance regimes that rely on extended periods of low demand to take circuits out of service.

Adaptation in the face of climate change and broader trends in the electricity supply industry will be necessary throughout the coming decades. An industry with a wider range of tools and technical solutions for planning and operation will be more prepared to manage capacity, stability and reliability at lower cost than if present methods do not evolve. The objective of transitioning to smart grid is undergoing considerable research and demonstration. Further development of techniques including customer participation through demand side response, energy storage, RTTRs, phasor-measurements and increased use of power electronics all have potential to increase network flexibility and release latent capacity.

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